CALIFORNIA ISO

California Independent
System Operator

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Vice President, Market Services

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August 8, 2003

Via Hand Delivery

Mr. Tom Carter
Power Operations Manager
Western Area Power Administration
Sierra Nevada Customer Service Region
114 Parkshore Drive
Folsom, California 95630-4710

Dear Mr. Carter:

Enclosed are the written comments of the California Independent System Operator Corporation ("ISO") regarding the Market Plan proposed by the Western Area Power Administration, Sierra Nevada Customer Service Region ("Western"), to become effective on January 1, 2005. This Market Plan contemplates the formation of a Federal Control Area ("FCA") by Western. The ISO has four primary concerns, which are discussed in further detail in the attached comments, with the Western Market Plan proposal:

- Adverse implications to Grid reliability and operations;
- Increased complexity of operating the California-Oregon Intertie, or COI;
- Increased costs to both Western's customers and California's consumers; and
- Inconsistency of Western's proposal with existing Federal policy and proposed direction.

The ISO has also been frustrated with the public process used in proposing the Market Plan. As early as April 2002, Western notified the ISO that it was considering forming a control area and pledged to allow the ISO to correct any inaccuracies in Western's assumption and analysis. However, Western then proceeded to provide information to its customers in December 2002 overstating ISO costs by a factor of 10. This information has never been corrected. In addition, upon the initiation of the analysis of the proposed Market Plan options by Navigant Consulting, Western again agreed to work with the ISO to ensure that any representations regarding ISO related costs were accurate. This was not done and as the attached comments demonstrate, the Navigant report contains numerous and costly mistakes that must call into question the very basis of Western's proposal and decision-making process. Western's lack of openness and forthcoming regarding its public process and the development of the 2005 Market Plan has been an issue for the ISO.

Moreover, Western initially stated that the decision to form its own control area would be cost based. Now that the real impact of the costs of the various Market Plan options is being understood more clearly, the criteria for this decision seems to have changed. It wasn't until the June 24, 2003 Federal Register Notice that the public learned for the first time that the "factors that it [SNR] will use in its decision-making process" are now flexibility, certainty, durability, operating transparency and cost-effectiveness.

We believe that the ISO's alternatives meet all of these criteria at a lower cost to Western's customers, while preserving a stable, well coordinated and well functioning transmission grid.

1. The ISO has already filed with the Federal Energy Regulatory Commission to become a Regional Transmission Organization, and the ISO offers the option of Western becoming a Participating Transmission Owner in the ISO structure to provide Western the avenue for providing integrated transmission service in California and recovery of its transmission costs. In addition, the ISO particularly offers the flexibility of the option of a Metered Subsystem ("MSS") for Western if it should remain in the ISO Control Area.

2. The ISO's transmission rates are based on FERC approved cost-of-service on an open and non-discriminatory basis to all market participants. The only volatility Western would experience is through buying and selling in the ISO's Ancillary Services and real-time Imbalance Energy market. However, this volatility is present regardless of whether or not Western becomes a control area, and the degree of volatility is based on Western's need to procure additional resources. Absent the need to procure resources, the volatility should not impact Western and its customers.

3. The ISO's operating protocols have remained substantially the same since the ISO start-up date in 1998. The only changes in operating protocols are based on the need to comply with changing operational criteria from the North American Electric Reliability Council ("NERC") and the Western Electricity Coordinating Council ("WECC"). However, every control area, including the Western Control Area, would have to make similar changes over time. Admittedly, the ISO has necessarily changed the protocols associated with markets, market implementation and market rules a number of times over the past six years. Given that the ISO was the first of its kind in the United States, an evolutionary process has been necessary when it comes to markets. Thus Western's concern with durability with respect to operating protocols has been met, but market durability is still evolving and will continue to evolve for a number of years to come. Western cannot disguise its concern regarding "operating protocol durability" as an off-hand reference to the energy crisis and

changing market rules. Moreover, the ISO's ongoing market modifications are designed to promote stability based on experience, best practices, and coordination of operations to the benefit of all California consumers and market participants.

4. It is unknown at this time how Western will implement its "operating transparency". However, Western's conduct in its public process and the development of the 2005 Market Plan has demonstrated lack of transparency. The ISO, on the other hand, offers transparency by posting its operational standards, protocols and market rules on the ISO website for all the world to see.

5. The cost assessments of the Market Plan options are analyzed further in the attached comments. The ISO alternatives could offer as much as $31 million in annual benefit to Western's customers.

6. Western's assumption that the ISO would continue to operate the COI as we currently do without negotiating with us the details and payment for such services, and preparing common procedures, is flawed at best. To protect our customers, we will insist on the preparation of such procedures and being compensated for providing this service.

While the ISO has made its best efforts in the attached comments to provide an objective evaluation of the Market Plan as the ISO understands it, the ISO believes that insufficient information has been provided thus far to make an informed decision about the Western proposal. The ISO alternatives meet Western's stated criteria at a lower cost; relieve concerns of reliability and complexity; and are consistent with the stated federal objectives. The ISO looks forward to working with Western toward a decision that will benefit both Western and all of California consumers.

If you have any additional questions, I can be reached at (916) 351-4435 or please contact Mr. Kyle Hoffman at (916) 608-7057.

Kindest regards,

Randall T Abernathy

Randall T. Abernathy
Vice President, Market Services

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Comments of the California Independent System Operator to the Western Area Power Administration – Sierra Nevada Region Regarding the Federal Control Area Plan for 2005

August 8, 2003

TABLE OF CONTENTS

I. Executive Summary

These comments summarize the perspectives, concerns, and positions of the California Independent System Operator ("ISO") regarding the Western Area Power Administration – Sierra Nevada Customer Service Region's ("Western") proposed Federal Control Area ("FCA") plan, as discussed in its 2005 Marketing Plan. The ISO has five primary concerns with Western's FCA proposal:

- Adverse implications for Grid reliability and operations due to more complex seams issues within California and configuration of the regional transmission system;

- Increased complexity of operating the California-Oregon Intertie by splitting control over one of the most important transmission interfaces in the western United States;

- Increased costs both to Western's customers and California's consumers due to inappropriate cross-subsidization of Western's customers through the pancaking of planned transmission surcharges for others; and

- Inconsistency of Western's proposal with existing Federal policy and proposed policy directions for greater coordination and reduced "balkanization" of regional electric systems.

- Western's FCA proposal is significantly more expensive than ISO-based options, such as Western's operation as a Metered Subsystem ("MSS") and/or joining the ISO as a Participating Transmission Owner.

In addition, the ISO is concerned that Western's decision on available operational alternatives is being made despite a fundamentally flawed cost-benefit analysis of these options. The ISO has identified a number of inconsistencies, errors and omissions in Western's cost-benefit analysis prepared by Navigant Consulting and has attempted to correct this analysis. The corrected analysis shows that the annualized cost of creating of a Federal Control Area are between approximately $10 million and $30 million per year higher those than ISO-based options, such as operation as a Metered Subsystem and/or joining the ISO as a Participating Transmission Owner. The ISO believes these alternative opportunities currently available to Western and its customers under the existing ISO structure will also avoid the increased complexities and costs that Western's FCA proposal would impose on California.

Moreover, the ISO has concerns with the federal process that has taken place to date. While the ISO has offered on numerous occasions, and been promised by the region manager an opportunity to coordinate assumptions and analysis, the promises were not fulfilled and errors and omissions have occurred in Western's analysis. Additionally, the lack of ability to decide on binding criteria for evaluating the alternatives is troubling.

Overall, the ISO is concerned that making a decision without an adequate basis is a recipe for disaster. As we will discuss further below, the existing information presented by Western is incomplete and erroneous, and any decision based on such information could jeopardize the reliability of the entire western U.S. transmission grid and impose unnecessary costs on electricity customers in the region.

The ISO's ultimate goal is to provide ***ALL*** California consumers, including Western's customers, with safe and reliable transmission service at the lowest reasonable cost. The ISO would invite Western to join forces in that effort and abandon the currently-pursued control area proposals which are clearly at odds with this goal.

II. Adverse Implications for Grid Reliability and Operations

The ISO's primary set of concerns with Western's proposal is the transmission "seams" issues that would result from creation of a new Control Area carved out of the current configuration of the ISO Control Area. This is a two pronged problem. First, the connections solely within the ISO Control Area are of issue. Then the impacts on the California-Oregon Intertie ("COI") connecting California and the Pacific Northwest are of concerns. Those issues are further explored in Section III.

Seams issues present adverse implications for the reliability and operation of the western transmission grid. The ISO, through participation in various member committees and workgroups, is aware that others within the Western Electricity Coordinating Council ("WECC") member systems and the WECC organization itself have expressed alarm and concern over the proliferation of new Control Areas. Because the ISO is extensively interconnected and integrated with Western's transmission grid, carving out the proposed new Federal Control Area would further complicate transmission operations in the region. Western's 230 kV and 500 kV transmission systems have numerous tie points to Pacific Gas and Electric Company's ("PG&E") transmission system (which is operated by the ISO) and creation of a Federal Control Area would disintegrate the present integrated configuration of the California transmission grid. The complexity inherent in operation of this grid as one system, let alone two, combined with the complexity associated with multiple Control Area operation of the COI (addressed in Section III), results in significant grid operation and reliability concerns.

If the new Federal Control Area is formed, the complexity and workload associated with pre-scheduling, path congestion mitigation, real time path de-rates, unscheduled ("loop") flow management, disturbance recovery, system restoration and outage coordination all would be increased to the detriment of reliable, efficient operations of both entities' transmission systems. The ability of the system operators to manage loop flows, as well as react to and control system disturbances, or to manage other significant events will be impaired because of the increased complexity and coordination of communications that would become necessary. While Western has acknowledged this increased complexity in its Federal Register Notice, we believe that it has understated the problem.

First, the introduction of another Control Area within the existing ISO Control Area would result in substantial additional complexity in intertie scheduling between the FCA and Western's Preference Power customers, which will remain in the ISO Control Area connected to the ISO Controlled Grid. Today this scheduling is done seamlessly. As many as 15 new interconnection points would potentially link the FCA and the ISO at a number of substations and transmission paths, including the Cottonwood, Round Mountain, and Tracy Substations.

Second, the additional Control Area would increase the complexity of Unscheduled Flow Mitigation, a Control Area function required by the WECC. Finally, coordination of planned and forced (real-time) outages would also be unnecessarily complicated if the FCA proposal moved forward.

Specifically, the ISO has the following concerns:

- **Potential for Actions Counterproductive to Grid Reliability:** Coordination of grid operations in California, particularly in Northern California, would be impaired. The ISO has great concern that Western would be compelled to take unilateral actions to serve its own needs without regard for the impact that these actions would have on energy flows in the ISO Control Area. *For example, if the ISO is mitigating a path overload on Path 26 or Path 15, there is concern that Western could be moving generation in its proposed FCA that would be counter to the mitigation actions the ISO is taking, and further, they would not feel compelled to coordinate these actions with the ISO, thereby negating mitigation actions the ISO is taking to relieve the overload, exacerbating existing conditions, compromising grid reliability, and subjecting the ISO to WECC Reliability Management System violations..*

- **Potential for Degradation of Voltage Support and Overload Mitigation Measures:** A separate FCA would result in additional complication in mitigating transmission line/equipment overloads and voltage support problems in the Sacramento Valley Area and Northern California. Western currently participates in the Sacramento Valley Study Group, along with the ISO, PG&E and other entities. However, it is unknown whether these entities would feel compelled to continue their participation in this group and to continue their contribution to grid reliability of the Sacramento Valley area.

- **Creation of Substantial Additional Complexity in Intertie Scheduling:** The ISO is very concerned with regard to how interchange and Generating Unit energy scheduling would be accomplished between the ISO, Western and the Bonneville Power Administration ("BPA") with the addition of fifteen new Control Area interconnection points. The dramatic increase in the volume and complexity of intertie scheduling that would result from the formation of the new Federal Control Area would not only result in substantial additional efforts and costs to perform those scheduling activities, but it would create complexities that would raise serious concerns for the reliability of system operations – particularly in the event of system emergencies or contingencies affecting those interties. The chief concerns in this area are the inability to control flows at any one particular scheduling point, the additional workload and associated employee positions that would be required at the ISO to accommodate these new scheduling arrangements, and the impact that uncoordinated (from an ISO perspective) or unilateral Central Valley Project ("CVP") generation changes would have on transmission line flows at the interchange points and in the ISO Control Area.

- **Complication of and Potential for Slower Response to Grid Contingencies:** On March 21 of this year, there was an incident at Southern California Edison Company's ("SCE") Vincent Substation that resulted in open loop operation of the Western Interconnection at Vincent Substation. If the systems were to be split into two Control Areas, this previously seamless response to such an emergency would require communication and rapid response by both parties to avoid a west-wide reliability issue.

- **Concern for Underfrequency Load Shedding for Western Customers Outside the FCA:** Western currently has approximately 800 meters serving its customer loads within PG&E's Service Area and, therefore, in the ISO Control Area. With that in mind, the ISO is concerned about Western's plan for compliance with WECC Minimum Operating Reliability Criteria ("MORC") Section 6-C, which addresses Automatic Load Shedding and System Sectionalizing and the WECC's Off-Nominal Frequency Operation Plan. This plan calls for a percentage of a Control Area's load to be capable of being shed through the activation of solid-state underfrequency relays to arrest interconnection frequency decay and uncontrolled separation in the event of a system emergency. It is unknown as to how Western would anticipate implementing such underfrequency load shedding requirement for the load served off these meters. This requirement is critical for maintaining the reliability of the regional transmission grid.

- **Concern for Reliability of Western Control Center Operations:** The ISO is also concerned about how Western would plan to comply with the WECC requirement of Control Area operators to maintain control area operations in the event that the primary control center becomes non-operational for any reason. The reason for the ISO's concern is twofold: first, the inability of Western to reliably operate their proposed Federal Control Area could impact the immediate local area in which the ISO control center is located; and second, Western's inability to operate its own control center reliably would very likely cause the operation of the proposed Federal Control Area to become immediately dependent on the ISO Control Area inasmuch as the ISO Control Area surrounds the Sacramento Municipal Utility District Control Area and virtually surrounds the entire proposed Federal Control Area.[1]

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[1] The ISO Control Center is approximately two blocks away from the Western Headquarters in Folsom.

III. Increased Complexity of Operating the California-Oregon Intertie

In addition to concerns regarding impacts of the Western proposal on internal ISO operations discussed in Section II, the ISO is further concerned that having three Control Areas involved in the operation of the California-Oregon Intertie ("COI") would unnecessarily complicate coordinated operations with neighboring Control Areas and significantly increase the complexities of reliably operating the interconnected grid in California. Western currently owns one of the major three transmission lines that comprise the COI transmission path. Having one of COI's three high voltage lines in Western's Control Area could adversely impact restoration and recovery time in the event of path derates, path separation, or other system disturbance. This could have negative consequences for the entire regional transmission grid. Additionally, there is a need to contractual establish the relationship of the parties at COI.

A. Reliability Risks

The formation of Western's proposed new Control Area would represent real reliability risks for the entire WECC. Most notable in this regard is the potential to degrade the reliability of the entire western interconnection by increasing the coordination requirements of the major interconnection path between California and the Northwest. Clearly, increasing the number of controlling entities, potentially affecting operations of all WECC member systems, would, at minimum, compromise emergency operations. Consider, for example, the impact of derates to the COI, which are based on a number of factors and conditions in California, the Northwest, and other portions of the west-wide transmission grid; problems with the Pacific DC Intertie ("PDCI") that more often than not have a direct and immediate impact on COI operation; or real-time Unscheduled Flow events and Mitigation Procedures. Creation of a Control Area that splits operational jurisdiction of such a significant path at the minimum would likely to result added confusion and misdirection during routine operations leading to errors and inefficiencies. More seriously, it could lead to miscommunication or delays during an emergency that could result in or worsen a major system disturbance.

The WECC member entities, and the customer load they serve, currently depend on the ISO, in close coordination with the Bonneville Power Administration ("BPA"), to operate the California-Oregon Intertie within extremely tight tolerances to facilitate reliability within the west-wide transmission grid. Adding a third Control Area to this operational arrangement would do little but compromise reliable operation of the COI; the California and Northwest transmission grids; and the entire west-wide interconnection.

Specifically, some of the concerns the ISO has with respect to operation of the COI if three Control Areas are involved are as follows:

- **Potential Adverse Consequences in the Event of Contingencies:** The need for increased coordination of path derates when forest fires are burning at or within two miles of any of the three 500 kV lines that. Unless this coordination is done efficiently and expeditiously, the COI transfer capability could be compromised. When a component of the COI is forced out of service, causing a de-rate of the COI transmission capacity in real-time, the ISO currently is able to utilize several methods to relieve the COI overload. The methods available include circulating the Pacific DC Intertie, initiating Control Area adjustments between the ISO and BPA, accepting decremental bids in the ISO's markets, if available, or cutting schedules in real-time. In the event of the formation of a separate Federal Control Area with elements of the COI in that Federal Control Area, the ISO's management of those COI contingencies would be complicated substantially. The ISO would have to coordinate any remedial actions with Western and could be limited in both the timing of its response and in its ability to use all of those response options.

- **Potential Path Restoration Delays:** Path restoration upon separation of the COI, as occurred on August 10, 1996, would be unnecessarily complex and require close coordination of four entities (ISO, BPA, PG&E and Western) and their field representatives. This would mean, at minimum, that six parties would have to engage at once to coordinate the closing of any individual substation circuit breaker that makes up the COI. This would lead to delays in restoration at times when interconnection reliability can hinge on decisions made and actions taken within minutes or seconds.

- **Outage Coordination Concerns:** The ISO coordinates outages of all COI components with BPA, PG&E and Western. This includes a requirement that Western provide the ISO 12-month advance notice of outages, updated quarterly. Additionally, the ISO currently has the ability to apply its outage protocols to Western with regard to the COI. This type of coordination ensures that COI capacity is maximized and allows COI outages to be coordinated with other internal system resources and interties, as well as BPA facility outages that affect COI. In the event of the formation of a new Federal Control Area, additional efforts would have to be made to ensure that outage coordination affecting the COI will be undertaken in a comprehensive and consistent manner.

- **Concerns for Mitigation of Pacific DC Intertie Outages:** The Pacific DC Intertie ("PDCI") runs from the Celilo Substation in Northern Oregon to the Sylmar Substation in Southern California, and is a parallel DC path to the Pacific AC Intertie ("PACI"). The PACI makes up a portion of the COI.

When the PDCI trips, depending on system conditions at the time, specific remedial action schemes ("RAS") may need to be utilized. Typically, immediate, well coordinated operating and Intertie scheduling actions are required of the ISO and BPA to mitigate resultant increased flows on the COI. In previous conversations with a Western representative, Western's opinion has been that any such resultant COI flows would simply be seen as "flow-through" and would not impact Western Control Area operations unless its lines were overloaded, and that the ISO would continue to operate the COI as if "nothing has changed." This position is unacceptable to the ISO, is inconsistent with standard utility practice for a Control Area Operator, and violates WECC operating procedures.

- **Complication of Mitigation of Unscheduled Flow (USF):** The ISO currently facilitates the WECC USF procedure for all COI schedules. When this procedure is implemented and fails to unload the COI, the ISO initiates further schedule reductions, circulates the PDCI if available, and in some cases makes inter-hour Control Area adjustments with BPA. In the event of the formation of a new Western Control Area, the ISO would have to undertake additional coordination with Western regarding any Control Area adjustments necessary to mitigation the COI USF.

- **Concerns with Western Operating Experiences:** Lastly, the ISO has general concerns based on past operating experience with Western, both pre and post ISO formation.[2] These concerns surround instances of poor communication regarding scheduled and forced outage coordination, real-time switching operations and scheduling operations of 500 kV transmission lines, often accompanied by a disconcertingly cavalier attitude toward such communication. The creation of a Federal Control Area within California increases the opportunity for these types of miscommunications that would only aggravate the impact toward transmission operations on a tightly integrated, yet "adjacent" ISO Control Area, which could have impacts on reliable operation of the interconnection and the regional power system.

B. Seams and Configuration Issues

The Western Federal Control Area proposal also would create different market rules for Market Participants depending upon which specific line they would be deemed to use at COI, and produce seams and configuration issues within the ISO Control Area, the proposed new FCA, and neighboring Control Areas that could affect reliability, reduce market efficiency, and increase costs to all of California's consumers.

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[2] A number of the ISO's staff came from various electric utilities and have prior personal experience with the operations of Western prior to restructuring and the inception of the ISO.

The ISO already is faced with Market Participants in the Northwest that have access to one or the other northern interconnection points, but not both.[3] Today BPA and the ISO operate the three COI lines as part of one path in a coordinated operation that allows derates on overall transmission allocation on COI to avoid the complete loss of some market participants' available transfer capability if one of the three COI transmission lines is out of service.[4] This existing operation benefits both Western's and all other California consumers.

Western stated that it would propose to have the ISO continue to operate the southern side of the COI even if Western created a new Control Area. However, Western has not addressed the cost and complexity of the ISO providing this service. Western would still have to negotiate and pay for Control Area services to reimburse the ISO for the costs of operating the entire COI transmission path in an integrated fashion under Western's Federal Control Area proposal. Additionally, Western would have to make its proportional share of scheduled net interchange adjustments in real time when events occur that reduce the Operating Transfer Capability on the COI whether or not the ISO remains as the path operator.

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3 BPA operates the northern half of the path and the ISO operates the southern half of the path. A number of Market Participants in the Northwest have access to either Malin or Captain Jack, but not to both. Today, with the seamless operation of the path, this distinction is not important. If the path is split into multiple Control Areas, the ability to deliver energy from the Northwest to California reliably and efficiently could be impeded.

4 The current terms of the Coordinated Operations Agreement for the path provides that if one line is out of service, then the schedules of all participants on COI are curtailed prorata by 2/3, rather than fully curtailing some market participants' schedules over COI while not at all curtailing others.

IV. Increased Costs to Both Western's Customers and California's Consumers

The ISO is particularly concerned that Western proposes to cross-subsidize some of its customers by creating an inappropriate transmission "surcharge" for others' use of Western's portion of the Pacific AC Intertie ("PACI") 500 kV line between Malin, Oregon and Round Mountain, California. Western essentially proposes to create a "toll booth" to collect revenues from transmission customers served by the ISO for the benefit of its preference power customers.

The apparent motivation is Western's perception that it should insulate its customers from the cost increases associated with the expiration of its 1960's era transmission contracts with PG&E. Western's plan would shift transmission costs from Western's federal preference power customers to all other electricity consumers that use the California-Oregon Intertie.

A. Background

Three of Western's contracts expire on December 31, 2004: (1) the integration contract (transmission and generation) between Western and PG&E (2948A); (2) the PACI transmission arrangement with California investor-owned utilities (2947A); and (3) the Malin-Round Mountain interconnection agreement with PG&E (2949A). Under the latter two contracts (2947A and 2949A), Western currently limits its use on the 1,600 MW Malin to Round Mountain portion of PACI to 400 MW in exchange for 400 MW of priority service from Round Mountain to Tracy.

Western currently uses the PG&E integration contract (2948A) to serve approximately 2,000 GWh of annual preference customer load connected to PG&E transmission or distribution facilities ("2948A customer load" or "2948A customers"). This contract, which expires at the end of 2004, has been in place since 1967. Based on information obtained from Western, the annual costs associated with serving 2948A customers over the PG&E transmission system amount to approximately $10 million. Due to the age of the contract, these transmission costs appear to be significantly below the current costs of providing transmission service.

Upon expiration of this PG&E contract, the cost of serving Western's 2948A customers would be, in large part, based on the charges for power delivery under the ISO's Tariff. Western initially estimated that the annual costs of serving these customers would increase by $23 million upon expiration of the contract. However, these cost estimates were significantly overstated due to a misunderstanding of ISO costs that Western would be facing. When corrected, the annual cost of serving Western's 2948A customer load appears to increase by approximately $8 million. This would increase the cost of power delivered to Western's 2948A customers by approximately 0.4 cents/kWh.

B. Western's Proposal to "Roll in" Increased Power Delivery Costs

Western is proposing to have these increased "CAISO delivery costs rolled into Western's transmission rate"[5] and use sales of its PACI transmission as a revenue source to offset the transmission cost increases that Western's 2948A customers would otherwise face as a result of the contract expirations. Western proposes that such increased costs "for use of ISO grid and PG&E transmission and distribution facilities to deliver Western power will be included in the [revenue requirement] for Western's PACI rights."[6]

To be able to insulate its 2948A customers from any transmission cost increases associated with the contract expirations, it appears that Western is proposing to (1) separate part of its system from the ISO and create its own Control Area; (2) take control over the entire 1600 MW capacity of the Malin to Round Mountain portion of PACI (while continuing to use only 400 MW by itself);[7] and (3) inflate the transmission rates for providing service on the remaining 1200 MW of PACI such that the excess revenues collected would offset any cost increases associated with expiration of Western's 1967-vintage contract with PG&E. Western's plan to create a new Federal Control Area also appears to require the condemnation of PG&E's Round Mountain and Cottonwood substations.

C. Concerns with Western's Proposal to "Roll In" Cost Increases

If implemented, Western's "pancaked" transmission surcharge on PACI would not represent economically legitimate recovery of transmission costs. Rather, it would violate the most fundamental principles of cost causation, restrain trade, and use an essential transmission facility (*i.e.*, the Malin to Round Mountain portion of PACI) as a "toll booth" to collect revenues from ISO customers in order to cross-subsidize Western's 2948A customers.[8] As a result of such cross subsidies, and instead of paying current ISO Access Charges for the use of ISO transmission service, Western's 2948A customers would continue to enjoy the current PG&E contract rates even after the expiration of these contracts.

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5 "Post-2004 Transmission Options," Western presentation, October 2002, page 6.

6 *Preliminary Rate Concepts for Post 04 Products and* Services, Western May 14, 2003 presentation, page 89.

7 Western is proposing to use Federal eminent domain authority to obtain the PG&E facilities at Round Mountain.

8 Western's June 24, 2003 Notice in the Federal Register also acknowledges that its proposal would create "[c]ost shifts ... to other users connected directly to the Federal transmission system or to entities seeking transmission service either on or through Western's transmission system to the CAISO-controlled grid." (CFR at 37,489).

This proposal would result in at least $8 million (or more) of additional annual charges for transmission service from Oregon and the Pacific Northwest into the ISO service territory. In other words, Western's proposal inappropriately would shift significant costs, ***conservatively estimated to be $80–100 million over ten years***, from its federal preference power customers to all other electric consumers in California and the surrounding region.

D. FERC Approval of Western's Proposal to "Roll In" Cost Increases

The ISO does not believe that the Federal Energy Regulatory Commission ("FERC"), which must approve Western's rates, would approve of such a rate allocation because it would be counter to long-standing Federal policy on this issue. In particular, Order No. 2000[9] noted that one of FERC's concerns with regard to finding the appropriate scope and configuration for Regional Transmission Organizations ("RTOs"), was to foreclose opportunities for such entities to "be placed to act as a toll collector on a critical corridor."[10] For Western to establish a higher price for "its" leg of the COI thus would be directly contrary to FERC's goals.

In conclusion, Western's transmission pricing proposal does not reflect underlying changes in costs and inappropriately cross-subsidizes Western's customers by imposing pancaked transmission surcharges for other customers' transactions over the California-Oregon intertie. This restricts trade and potentially harms both the competitiveness and efficiency of the regional market. It would also reduce the transparency of transmission pricing and raise a new set of "seams issues" by creating two different pricing regimes for what is now a single transmission path.

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9 *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12088 (2000), FERC Stats. & Regs. ¶ 31,092 (2000), *appeal dismissed, Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

10 Order No. 2000 at 31,079-80.

V. Inconsistency With Existing Federal Policy and Proposed Direction

The ISO also is concerned that it would be poor public policy to support further fragmentation and further rate pancaking of the western transmission grid when the economic and social implications of reliability and efficient grid operations have become so apparent in this region over the past decade. Adoption of this proposal, contrary to the Federal policy goals striving both for better integration and coordination among electricity systems and transmission rate "de-pancaking" to foster regional trade, would instead further balkanize the western transmission grid.

Federal energy policy on this subject is unambiguous. Dating back to at least the time of Order No. 888,[11] one of the stated goals of FERC has been to provide for greater coordination within regions. This idea was carried forward through Order No. 2000, in which FERC detailed the benefits to be gained by properly structured Regional Transmission Organizations ("RTOs"), with the goal of promoting "efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest possible price for reliable service."[12] FERC continued its push for a broader approach to markets and market rules in its wholesale market platform initiative. The April 2003 FERC White Paper on this subject states that "[r]egional operation is critical for both reliability and efficiency because power flows freely throughout regional grids."[13]

The Department of Energy ("DOE") shares FERC's goals with regard to applying consistent rules across the broadest possible geographic areas. For example, the DOE's report to Congress on FERC's Standard Market Design ("SMD") proposal found that the open wholesale electricity markets that would result from successful SMD implementation would provide savings for U.S. consumers of approximately $1 billion/year in the near term, and $700 million per year in the long term.[14] Further, the 2002 DOE National Transmission Grid Study affirms

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11 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and rev'd in part sub nom. Transmission Access Policy Study Group, et al. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

12 Order No. 2000 at 30,991. One of the four characteristics that Order No. 2000 found necessary to an appropriate RTO was that it have sufficient scope. *Id.* at 31,076.

13 Federal Energy Regulatory Commission, *White Paper, Wholesale Power Market Platform*, April 28, 2003 ("White Paper"), at 7.

14 U.S. Department of Energy, *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*, DOE/S-0138 (April 30, 2003), at ix.

that regional operation and planning of transmission is essential for ensuring reliable and affordable electricity now and in the future.[15] Moreover, Energy Secretary Spencer Abraham has himself clearly stated a preference for reducing regional boundaries and obstacles in the provision of electric transmission to the greatest extent possible:

> At present our transmission system consists of a series of loosely connected, balkanized regional grids. Transmission bottlenecks between and within these grids cost American consumers hundreds of millions of dollars annually and threaten the reliability of our electric service. Our 21st Century economy needs an electric system on which electricity can move from coast to coast without having to stop for red lights, stop signs, and tolls along the way.[16]

Formation of a separate Western Control Area, and a toll on the California-Oregon Intertie, would be in direct contradiction to these critical policy goals. The FERC White Paper declares that "[t]o avoid having customers pay multiple, cumulative charges for transmission service across multiple utility grids in a region, the rate paid by a customer should permit that customer to have access to the entire region at a single rate."[17] The DOE Grid Study, as well, stresses the importance of eliminating rate pancaking:

> Pancaked transmission rates create economic distortions in bulk-power markets by preventing some trades that would be profitable if not for the multiple transmission fees involved...The economic impacts of eliminating rate pancaking are even more dramatic. The benefits to consumers from more efficient trade are more than $1 billion per year.[18]

In spite of this clear Federal policy, however, assessing "multiple, cumulative charges" appears to be precisely what Western plans to do under its new Control Area proposal.

In addition to the foregoing conflicts with sound Federal policy, Western's proposal to exercise the power of eminent domain over PG&E's Round Mountain

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15 U.S. Department of Energy, *National Transmission Grid Study*, May 2002 ("2002 Grid Study"), at 8; 24-28.

16 Remarks by Energy Secretary Spencer Abraham, Secretary of Energy Advisory Board Meeting, Arlington, VA, May 8, 2002.

17 White Paper at 8.

18 2002 Grid Study at 26. It is evident from this statement that, in the view of the DOE, the gains to be achieved by reducing pancaking may be obtained independent of whether SMD is implemented.

Substation just to facilitate its ability to impose its proposed "pancaked" transmission rates is contrary to sound public policy for the use of the power of eminent domain. Moreover, there is an obvious potential for protracted legal proceedings associated with any attempt by Western to condemn those PG&E facilities. Neither of those prospects should be acceptable as Federal policy.

VI. Flaws in Western's Analysis of Costs and Benefits

Western has presented an *Analysis of Central Valley Project Operational Alternatives,* which was prepared for The Bureau of Reclamation and The Western Area Power Administration by Navigant Consulting, Inc. The analysis, dated June 12, 2003, is an attempt to quantify costs and benefits under four operational alternatives: (1) operating as a Participating Transmission Owner in the California ISO ("PTO Option"); (2) operating under the ISO Tariff as a Wheeling customer of PG&E and the ISO ("Wheeling Option"); (3) operating under the ISO Tariff as a "Metered Subsystem" ("MSS Option"); and (4) operating as a separate electric Federal Control Area in California comprising all or portions of the Central Valley Project ("CVP") facilities and customers ("FCA Option"). Under the FCA Option, Western's cost-benefit analysis explores four different Federal Control Area configurations.

Navigant officials noted at the July 9, 2003 Western Public Information session that the assumptions used in the report were provided by Western and that no analyses were performed to evaluate the sensitivity of the report's findings to different assumptions. Although the ISO offered to work with Western in the evaluation of its operational alternatives, Western did not consult the ISO to verify the reasonableness of Western's assumptions.

The ISO has reviewed Western's cost-benefit analysis of CVP operational alternatives, and appreciates the additional efforts that Western's and Navigant's staffs have undertaken to better document the analysis and assumptions made in the July 9 report. While justifications for some of the assumptions used in Western's report are still undocumented at this time, the ISO has identified several significant errors and omissions that systematically overstate the advantages of establishing a Federal Control Area and underestimate the cost savings, financial benefits, and operational efficiencies of the options under which Western would remain in the ISO Control Area (collectively referred to as "ISO Options").

Based on this review, the ISO finds that Western's cost-benefit analysis:

- significantly *overstates* Western's costs associated with ISO Options, including Western's capital and operating expenses, ISO Control Area operations costs, "Reliability Service" costs, and balancing energy and congestion costs;
- *understates* both the financial benefits received by participation in the ISO and the incremental costs associated with the formation of a Federal Control Area;
- likely *understates* the operating reserves that Western would have to carry as a stand-alone Control Area, resulting in overstated opportunities for ancillary service sales under the FCA Option; and
- *excludes* payments that Western (admittedly) would be required to make to the ISO under the FCA option for the costs associated with the increased

complexity of coordinated grid operations of COI and the two Control Areas.[19]

As further discussed below, the ISO has corrected misrepresented costs and benefits of Western's study. ***Doing so shows that the creation of a new Federal Control Area is not the least-cost option for Western's CVP customers.*** Even without quantifying the operational complexities, inefficiencies, and configuration problems that a new Control Area would create, the corrected analysis of direct costs and benefits associated with various alternatives shows that the **Federal Control Area Options are between $9 million and $31 million per year more expensive than ISO-based operational alternatives.**

A. Critique of Western's Cost-Benefit Analysis

Western's study developed estimates of future costs and revenues for each of the operational alternatives over a 15-year study period from 2005 through 2019. The study reaches the erroneous conclusion that creation of a Federal Control Area is the least-cost option for Western's CVP customers, resulting in annual savings of approximately $10 million. This conclusion is driven by faulty assumptions based on a number of misunderstood or misrepresented costs and benefits, as follows:

- **Ancillary Services ("A/S") Obligations and Sales Opportunities:** Western's analysis misinterprets the ISO's treatment of self-provided Ancillary Services. The report assumes that the Western load would incur a 6.2% A/S operating reserve obligation under the ISO Options based on an assumed average A/S need for the ISO Control Area, but only a 5% obligation (due to 100% coverage of Western loads with hydroelectric generation) under the Western's FCA Option. This assumption is inconsistent with the ISO Tariff. Under ISO settlements for self-provided A/S, Western is credited for A/S operating reserves at the same 5% hydroelectric rate as it would under its FCA Option. The Navigant Report also misattributes benefits of A/S sales opportunities based on the erroneous 1.2% difference (6.2% less 5%) in assumed operating reserve requirements for the ISO and FCA Options.

  The operating reserve requirement under the FCA Option would likely exceed the assumed 5% and, as a result, would be larger (not smaller) than under ISO-based operational alternatives. This potentially added reserve obligation under the FCA Option is based on the WECC requirement that a Control Area must provide operating reserves equal to the larger of its *single largest contingency* or the assumed 5% for load served by hydroelectric generation. Western's single largest contingency may frequently be significantly larger than 5% of its Control Area load served by hydroelectric generation. Indeed,

[19] Even though Western has offered to compensate the ISO for the increased operating costs imposed by the Western plan, the ISO has not been presented with a proposal, nor has Western discussed with the ISO the parameters of such activity or cost.

Western's single largest contingency may be as high as 520 MW — equal to the loss of Western's 230 kV line to the Sutter Power Plant and the subsequent loss of all Sutter generation. In comparison, even at a peak load of 1600 MW, Western's 5% reserve requirement under the ISO Options only would be 80 MW. Thus, Western's operating reserve obligation as an independent FCA could often be significantly higher than the assumed 5%.[20] If Western were to rely on "reserve sharing" with other Control Areas to mitigate the single largest contingency obligation, then not only would its alternative A/S operating reserve obligation likely be greater than 5% due to the need to rely on other Control Areas with less than 100% hydroelectric generation, but adequate transmission would need to be reserved between the respective pool members sharing in the A/S obligation. No such added A/S requirements or imputed transmission reservation costs have been considered in Western's analysis.

If Western were to hold reserve capacity based on its own single largest contingency obligation without a reserve sharing agreement, its WECC obligation under the FCA option (likely in excess of 300 MW) would be four times its operating reserve obligation under the ISO Options. In contrast to Western's estimate that it would face a $600,000 disadvantage in terms of A/S sales opportunities under the ISO Options, the lower ISO A/S requirements under the ISO Options would likely create an annual *benefit* of $3.5–4.5 million for the ISO Options over the Western FCA proposal.

- **Reliability Services (R/S) Costs:** The Navigant Report incorrectly assumes that Western's Central Valley Project customers would be fully liable for PG&E's Reliability Services costs if Western were to become a Participating Transmission Owner ("Participating TO" or "PTO"), and that its customers would be partly liable for PG&E Reliability Services costs under the ISO Metered Subsystem alternative. In contrast, under the FCA Option, Reliability Service charges are not applied to Western's directly served loads. These assumptions create an erroneous $10 million annual disadvantage for the PTO Option and an erroneous $4 million annual disadvantage for the MSS Option in Western's study.

  In fact, in accordance with the existing ISO Tariff, Western's load would not face the assumed $17.5 million in Reliability Services costs under the PTO Option because load in one PTO's Service Area is not obligated to pay the Reliability Services costs of another Participating TO. As a Participating TO, Western would not incur its own Reliability Services costs and at least some of the load points currently served over PG&E transmission would likely be part of Western's PTO Service Area and, thus, also be exempt from PG&E's R/S costs. Relative to other

[20] This increase in Ancillary Service requirement will impact the hydroelectric generation from the USBR generating units and may cause power needs to be the highest priority use of the USBR water delivery system.

operational alternatives, becoming a Participating TO consequently would *reduce* (not increase) the total Reliability Services costs faced by Western's load.

- **Congestion costs:** Western's study assumes that its Central Valley Project customers would incur congestion costs on the Pacific AC Intertie ($5.5 million annually) *only* if Western were to join the ISO as a Participating TO. However, this assumption ignores the Firm Transmission Rights ("FTRs") that Western would be allocated under the ISO's Access Charge structure, commensurate with its Existing Contract rights on the Pacific AC Intertie, for the duration of those rights. As a result, Western likely would receive a full financial hedge against congestion charges. Although Western's analysis assumes that its Existing Contracts would continue over the 15-year study period, this benefit of receiving FTRs for Existing Contracts under the PTO Option is not reflected in Western's analysis. Similarly, under the ISO's market redesign, Western would be allocated congestion revenue rights ("CRRs") for their converted Existing Contracts. If the Existing Contract conversion were insufficient to meet the same level of CRRs that the ISO will provide load-serving entities, then Western, as a load-serving entity, would obtain additional CRRs that would provide a nearly complete financial hedge against congestion charges. Consequently, under either scenario, there would be little or *no* adverse financial impact on Central Valley Project customers resulting from congestion on the Pacific AC Intertie if Western joined the ISO as a Participating TO.

  The Navigant Report also overstates the incidence of congestion on COI relative to recent operational history. The Navigant Report assumes, apparently based on 1999-2001 data (*i.e.,* including the 2000/2001 Western power crisis), that the COI would be congested 26% of the time. However, more recent experience shows that congestion on COI has been declining. In 2002, COI was congested only 16% of the time. The combination of ignored FTR/CRR benefits and overstated congestion on COI erroneously disadvantages the PTO Option by approximately $5.5 million annually in Western's analysis.

- **Capital and operating costs under the MSS Option:** Western assumes that the MSS Option would require significant additional costs, including the acquisition of Automatic Generation Control ("AGC") hardware, new settlement software, and additional personnel. However, Western essentially is already operating as an MSS today, without the assumed additions of hardware, software and personnel. Western could operate as an MSS with full 10-minute load following capability without the addition of AGC hardware, software or personnel, a Market desk or new settlements software. Even when accepting the capital and operating costs Navigant has identified for the PTO Option (which already includes the CVP metering investment required for the MSS Option), recognition that operation of a Metered Subsystem would not require any additional expenses means that Western's study overstates the costs of the MSS Option by over $5 million annually. The cost of the ISO Options would be even lower if Western decided to avoid system upgrades that are not needed to operate as a Participating TO and/or MSS. Western's analysis also ignores that additional benefits of $2-6 million annually can be achieved if the MSS Option is implemented in conjunction with Western joining the ISO as a Participating Transmission Owner.

- **Western's Transmission Revenue Requirement ("TRR") and ISO Access Charges under the PTO Option:** Based on data from the ISO's FERC transmission Access Charge proceeding, Western may be understating its TRR by approximately $2.9 million. Since the TRR is a "benefit" under the PTO Option, this potential understatement of Western's TRR creates a fictitious $2.9 million annual disadvantage for the PTO Option in Western's analysis. In addition, Western assumes that under the PTO Option it would be forced to pay the ISO's Access Charge on its entire gross load. However, based on a recent FERC order, a new Participating TO that also operates as a Metered Subsystem would pay the ISO's transmission Access Charge only on net load. Under this treatment of MSS load for new PTOs, if implemented and reaffirmed by FERC, Western's analysis would further overstate PTO-related costs by $4.5 million a year.[21]

- **COI (Path 66) Operator Costs:** The Navigant Report's analysis overlooks the payments that Western would make to the ISO in its role as California-Oregon Intertie Path operator. Western has acknowledged that its Control Area proposal complicates operation of the grid, and that the ISO should be compensated for this service. Since ISO's costs of operating COI and coordinating WAPA and ISO transmission rights on this path are not included in Western's analysis, the costs of Federal Control Area operations are understated.

- **Other ISO Costs and Charges:** Western's assumed cost of various ISO charges—unaccounted for energy, neutrality, grid operations, and ancillary services—are also overstated. This is because Western based these costs on averages for 1999-2001, a period which includes the California power crisis, when prices were at unprecedented levels. Such prices are not representative of market conditions going forward (particularly when inflated at 3%-4% per year). ISO Market mechanisms have since been put in place to preclude the high prices of the power crisis from recurring (*i.e.*, Automated Mitigation Procedures or "AMP", FERC price caps and the State's forward energy contracts for the IOUs'

21 The ISO will be filing on August 11, 2003 to request rehearing on this issue due to the inequity of this rate allocation to New Participating TOs versus the Original Participating TOs.

load). Average ISO market "charges" to load (unaccounted for energy, neutrality, grid operations, assuming self-provided A/S) were assumed to be 79 cents/MWh (escalated at 3% per year) in Western's analysis, but were actually only 26 cents/MWh in 2002 and are even smaller in the first half of 2003.

Western's analysis of the PTO Option also includes "deviation costs" based on the assumption that Western on average would purchase 3% of its energy from the ISO real-time Imbalance Energy market at high assumed costs. However, if Western is in fact able to serve 100% of its Federal preference power loads (as is assumed under the FCA option), no such "deviation costs" would be incurred. Even without load following under the PTO or MSS Options, Western's "deviations" would be positive in some hours and negative in others. As long as Western on average supplies 100% of its load, the positive and negative "deviations" will offset each other and generally net to zero. Together with overstated charges for unaccounted for energy, neutrality, and grid operations, the erroneous imputation of "deviation charges" adds more than $6.5 million in exaggerated costs for the PTO option, which translates into a *fictitious* advantage of equal size for Western's FCA Option.

- **Biased Use of Cost Escalation Rates:** Western's analysis escalates all ISO charges by 3% or 4% a year whereas Western's operating costs, capital costs, and TRR are held constant for the entire 2005-2019 study period. There is no justification for escalating ISO related charges while assuming that Western's expenses will remain the same. Western would face the same cost pressures (*e.g.*, labor, materials) in the same market (Northern California) as the ISO. If Western's operating costs had been assumed to escalate by 3% as well, it would have added $3 million annually to Federal Control Area costs in the last year of the study period. Assuming Western's Transmission Revenue Requirements also would grow by 3% a year (consistent with the assumption that the ISO's transmission rates grow 3% a year), the FCA Option would see an additional $5 million annual disadvantage in the last year. Escalating ISO costs while Western's own costs are held constant is inappropriate and inconsistent with proper economic evaluation of various options.

B. Correcting Western's Analysis Shows that PTO and MSS Options Result in Significant Cost Savings Relative to the Creation of a Federal Control Area

The ISO analyzed the information received to date in response to the ISO's request for work papers to Western's cost-benefit analysis. After conservatively correcting the errors and inappropriate assumptions itemized and discussed above, the analysis shows that the MSS and PTO Options are between $9 million and $31 million per year *less* expensive than the Federal Control Area Option. (These financial advantages of the ISO Options relative to creating a new Control Area within the heart of the ISO's Northern California service area are in addition to the previously discussed indirect costs associated with the seams, configuration, and operational issues that the Federal Control Area option would impose.) The ISO continues to work with Western to refine this analysis further and to clarify several residual concerns regarding the assumptions made by Western for the June 12, 2003 Navigant Report.

Table 1 in the Attachment A to these comments summarizes the ISO's correction of Western's cost-benefit analysis. The attached table presents costs and benefits in the same general format as Table 1 in Western's Report. In addition to the MSS and FCA Options analyzed in Western's study, the corrected analysis presented in Attachment A shows costs and benefits for two PTO Options: (1) Western as a New Participating Transmission Owner operating a Metered Subsystem ("PTO+MSS Option"); and (2) Western as a new PTO but without operating a MSS ("PTO Option"). The results of correcting Western's cost-benefit analysis show that the net benefits of MSS and PTO Options clearly and substantially exceed those of forming a Federal Control Area. The results also show that the operation of a Metered Subsystem by Western as a New Participating Transmission Owner is the least-cost operational alternative.

Operational Alternative	2005 Net Costs	Savings vs. FCA Option
PTO+MSS	$22-29 million	$16-31 million
PTO	$28-31 million	$15-25 million
MSS	$37 million	$9-16 million
FCA (Group B customers)	$45-53 million	$0

Source: Attachment A, Table 1

C. Corrections Made to Western's Cost-Benefit Analysis

The following corrections and adjustments were made to Western's cost-benefit analysis based on the errors and inappropriate assumptions documented above. The cost and benefit components itemized below are organized in the same sequence as the costs and benefits listed in Western's analysis and Table 1 in Attachment A. Where appropriate, two different scenarios are evaluated for cost items to provide a reasonable range of results—one that is more favorable to the Control Area option and an alternative scenario that is more favorable to the ISO Options.

1. *Cost Components*

(a) Grid Management Charge: Billing units for FCA, Group D customers, are adjusted to equal the billing units for FCA, Group C. This adjustment is consistent with the reality that, even if dynamically scheduled, GMC would be charged (on a net basis) to Western's load inside the ISO Control Area. (As noted below, consistent with Western's assumed trend in its own operating costs, GMC charges and all other ISO costs were held constant in real terms over the 2005-2019 study period.)

(b) Transmission Access Charges: The adjusted analysis evaluates two scenarios: (1) costs of ISO transmission access are equal to those for 2005 in Western's study; and (2) ISO access charges are assessed on a net load (rather than a gross load) basis for the PTO+MSS Option. The latter is consistent with a recent FERC ruling. Charges and billing units of all other operational alternatives are equal to those in Western's study.

(c) Ancillary Service Costs: A/S requirements are assumed to be the same regardless of whether Western joins the ISO (as a PTO or MSS) or forms its own Control Area. This is a conservative assumption since it is unlikely that Western operating reserves requirement under the FCA option would be as low as the 5% required for self-provision under the ISO Options. As discussed previously, even under a reserve sharing agreement, it is unlikely that Western could reduce its operating reserve requirements to 5%. The corrected analysis also removes Western's assumption that, in addition to self-provision of A/S, Western would face charges for replacement reserves. No such charges would exist if Western self-provided its A/S requirements; moreover, the ISO no longer buys replacement reserves, and does not plan to in the future.

(d) Transmission Congestion Costs: Western's analysis was corrected to reflect the fact that any congestion charges Western may incur on COI would be fully or almost fully hedged through FTR or CRR benefits. The revised analysis shows results for a 100% hedged and, conservatively, an only 80% hedged alternative. In addition, under both scenarios the incidence of transmission congestion on COI (in the import direction) is reduced to 16%, rather than the 26% assumed by Western, to reflect actual congestion on COI in 2002.

(e) Reliability Service Costs: Western's assumption of how much of its load is exposed to PG&E's R/S charges has been adjusted to reflect the fact that under the PTO Options PG&E's R/S charges would not apply to any load in Western's PTO Service Area in accordance with the ISO Tariff. In addition, since Western only supplies part of its preference customers' load, it is unlikely that all of Western's load could avoid PG&E's R/S charges even under the FCA, Group D option. We conservatively assume that only 50% of Western's load in PG&E's

current service area would be able to avoid R/S charges under the PTO and FCA-Group D Options.

(f) Deviation Charges: Although Western will at times be "long" and at other times "short" under the PTO and MSS Options (which do not require load following), this will average out over time. Thus, deviation charges are zero across all scenarios. This is also consistent with Western's assumption that it will supply 100% of its scheduled loads under the FCA Options.

(g, h, i) Charges for Unaccounted-For Energy ("UFE"), Neutrality, and Grid Operations: The combined charges for UFE, Neutrality and Grid Operations charge is set to be $0.26/MWh, consistent with actual 2002 ISO operational experience.

(j) Annualized Capital Costs: Even today, Western essentially could be operating as an MSS without the assumed significant additions of hardware, software, and personnel in Western analysis. To be conservative, under one scenario we accept Western's assumed additional capital costs for the PTO option (which already includes the CVP metering equipment necessary for MSS operations) but apply these PTO capital costs to the MSS and PTO+MSS Options as well.[22] Under an alternative scenario, we assume that Western only would need to purchase approximately half of IT-related infrastructure assumed its analysis if it were to become a Participating TO or MSS. This adjustment reduces the assumed capital costs for the ISO Options by $1.4 million. No adjustments were made to Western's assumed capital costs for the FCA Options under either scenario, although these costs would likely increase with the scope of dynamically scheduled load under FCA-Groups A through D.

(k) Operating Expenses: The adjusted analysis evaluates two scenarios. Under both scenarios, the annual operating expenses of Western's FCA Options are increased by $1.5 million to reflect additional payments that Western admittedly would need to make to the ISO in its role as the COI Path operator and transmission coordinator. (Note, however, that this value is simply a placeholder as the ISO has not quantified its added operating costs under the FCA Options nor have any discussions taken place on this issue with Western). Because operation of an MSS does not require Western to incur certain costs (e.g., operating an AGC desk, increase transmission maintenance, or acquire new substations), we conservatively assume in one scenario that operating expenses for the MSS and PTO+MSS Options are equal to Western's assumed PTO operating expenses. In the second scenario, we reduce the assumed IT-related operating costs for the ISO Options, consistent with the assumed reduction in IT-related capital costs described above. This adjustment reduces the assumed operating costs for the ISO Options by about $900,000.

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22 Note that, in contrast to Western's assumption, operation of an MSS would not require Western's acquisition of PG&E's Cottonwood substation through Federal eminent domain authority.

(I) Transmission Revenue Requirement: Two measures of Western's TRR are used in the revised analysis, the value assumed by Western (approximately $9.6 million) and the TRR developed from data Western provided in the FERC transmission Access Charge proceeding (approximately $12.5 million).

2. Benefit Components

(a) Ancillary Service Sales: Western's analysis was corrected based on two scenarios. In the first scenario, we conservatively assume that A/S sales opportunities are the same across all ISO and FCA Options – which is consistent with the unlikely possibility that Western's operating reserve obligation as an FCA would be the same 5% as its obligation under the ISO Options. The second scenario assumes that, due to higher (e.g., first-contingency based) operating reserve requirements under the FCA Options, Western would be forced forego an average of 280 MW of A/S sales opportunities during 80% of all hours based on recent A/S prices. This scenario is also conservative given that (i) Western's reserve obligation based on its single largest contingency may be as high as 520 MW; and (ii) we reduced Western's assumed A/S prices from the unreasonably high levels experienced during the 1999-2001 period (as assumed in Western's study) to the lower A/S prices experienced since the Fall of 2001.[23]

(b) Transmission Payments: The access charge revenue disbursements that Western would receive from the ISO as a PTO are set equal to Western's TRR in the two alternatives discussed above: (1) $9.6 million, consistent with the assumption in Western's cost-benefit analysis, and (2) $12.5 million, consistent with the data Western's provided in the Access Charge proceeding. The former value is most conservative because it yields a comparatively lower benefit under the PTO-only and PTO+MSS Options.

3. Trending of Costs Over Time

Consistent with Western's assumed of trends in its own operating costs (i.e., no increase over time), all ISO-related costs and charges are also assumed to remain constant over the study period. As shown in Table 2 of Attachment A, this correction of unreasonably divergent cost trends means that the costs and benefits of ISO and FCA Options are similar to those for 2005 and do not change over the remainder of Western's 2005-2019 study period.

23 In addition, sales of replacement reserves are excluded from the analysis because, as noted above, the ISO no longer purchases this A/S service.

VII. ISO Alternatives

With the termination of the PG&E contracts, Western and the U.S. Bureau of Reclamation ("USBR") must have a contractual relationship with the ISO. The ISO has offered a number of alternatives to Western, USBR, and Western's customers as an alternative to establishment of Western as a Federal Control Area, including a Participating Transmission Owner option and a Metered Subsystem option designed to meet the specific needs of Western. Absent one of these options, Western or USBR will be required to execute a Participating Generator Agreement, and Western would potentially need to enter into a Utility Distribution Company Operating Agreement to establish the parameters between the ISO and Western. If Western forms the FCA, an Interconnected Control Area Operating Agreement will be required to establish the terms and conditions between the two entities.

A. MSS Option

With or without Western participation in the ISO as a PTO, the MSS option offers several benefits to governmental entities under the ISO Tariff. It is a lower-cost alternative that essentially would maintain the existing operating relationship between the ISO and Western, avoiding the added cost, complexity, configuration, and grid reliability issues associated with the interposition of a third Control Area on the Pacific AC Intertie and allow Western to maintain control over its system and resources absent a Control Area emergency. The MSS option is sufficiently beneficial for governmental entities that three entities representing eleven different municipal utilities have entered into MSS agreements with the ISO, and others are actively considering that option.

The MSS option would essentially maintain the present Western relationship with the ISO, with the primary exception that Western would serve as its own Scheduling Coordinator, as opposed to relying upon PG&E. PG&E presently schedules on behalf of Western and its customers due to its 2948A integration agreement with Western, which expires on December 31, 2004.

ISO Metered Subsystem benefits would include:

- ISO cost allocation and settlements based upon cost causation principles;
- Load following allowed as an option (but not required) in real-time, providing Western with the ability to avoid reliance on the ISO's imbalance market (for positive *or* negative deviations) should it so choose;
- Dispatchability of multiple U.S. Bureau of Reclamation Generating Units as System Units with substantial limitations on ISO dispatch authority, including exemption from the ISO "must-offer" obligation, which affords Western and USBR virtually complete control over Federal Generating Units and watersheds;
- Exemption from non-contingency firm Load Shedding;

- Full access to ISO real-time Energy and Ancillary Services markets; and
- Continued provision of ISO Control Area services, at a lower cost than the FCA option.

The ISO's MSS Options can be tailored to address the specific needs of the USBR Federal generation and Western as a Federal transmission agency. Execution of ISO agreements does not result in FERC jurisdiction over Western's customers. If Western executes an MSS Agreement, the ISO is not aware of any additional FERC encumbrances that would apply to Western or, its customers. If Western also executes the Transmission Control Agreement to become a Participating TO, then its rates are reviewed and approved by FERC, no different than today.

The ISO can offer Control Area services at a lower cost than Western due to economies of scale and avoidance of duplicative systems. The ISO is concerned for the overall cost implications for all California consumers, including Western's customers, that creation of a new Control Area would cause.

The ISO's objective is to provide Western with a lower cost alternative that meets Western's and USBR's operational needs and retains Western as an integral part of the ISO Control Area. The following elements comprise the ISO's offer of a tailored MSS for Western and the U.S. Bureau of Reclamation:

- **MSS methodology to model Western "Bubble" or service area:** The Western MSS would likely include the City of Redding, the City of Shasta Lake, Lawrence Livermore National Lab, and the Tracy pumps. In addition, the Calpine Sutter Power Plant is located within the proposed Western MSS. If it continued to operate as an independent Participating Generator, at Western's option, the Sutter plant could be excluded for purposes of the ISO's scheduling and settlements with Western's MSS. Each of these entities is located within the existing Western service area boundaries (i.e., the Western bubble). This service area could comprise a MSS, subject to Western's preferences.

- **Settlements:** The ISO would provide Western with "net" Settlements treatment for various ISO market charges (i.e., Neutrality) as appropriate, based on cost causation principles.

- **Unaccounted-for Energy (UFE):** No PG&E UFE charge would be applied to load within Western's MSS service territory.

- **Load Following:** Western would have the option (but would not be required) to choose to follow its load with its generation without incurring uninstructed energy deviation penalties. Uninstructed generation and load deviations would be netted for the purpose of determining whether or not deviation penalties apply. Alternatively, Western would have the option to utilize the ISO's Imbalance Energy market to provide for its generation and load deviations, in accordance with ordinary ISO processes. In either event, Western would only be required to install ISO-polled metering at its Generating Units and points of connection to other utilities, and would not be required to install any AGC equipment.

- **System Unit:** Western and USBR would have the ability to schedule customized combinations of generating units on a System Unit basis (aggregating resources for scheduling and settlements) to provide USBR with flexibility in dispatching individual generating resources. It is anticipated that USBR Shasta area generation and Folsom vicinity generation would comprise at least two separate "System Units". New Melones either would be included with the Western MSS as a third "System Unit" or treated as a separate generating resource, at Western's discretion. Western would be required to install telemetry equipment at those aggregations of generating resources to communicate directly with the ISO's Energy Management System ("EMS") but would not be required to install its own AGC system.

- **Market Participation:** Western would have full access to all ISO markets and associated services using the USBR System Units without the need for Western or USBR to execute a Participating Generator Agreement. In addition, the MSS option would provide USBR and Western complete operational control over their generating resources, except in the event of a major system emergency, with respect to participation in the ISO's markets. The USBR units would not be subject to ISO dispatch and would be exempt from the ISO's "must-offer" requirements, unless Western chose to bid these units into the ISO's markets.

- **Multiple SC ID Accommodation:** Western would have an option for continued use of multiple individual Scheduling Coordinator IDs (SC IDs), as required to facilitate and simplify Western's "ISO" settlements with its "scheduling agent" customers located on the ISO Controlled Grid but external to and scheduled separately from the Western MSS.

- **A/S Requirements:** Western's ISO A/S obligations would be based on gross load as a proportionate share of ISO A/S requirements for the entire ISO Control Area. However, Western would continue to have the option of self-providing its A/S obligation with its own hydro generation resources, at the 5% rate for all load served by hydroelectric generation.

- **ISO Control Area Services:** The ISO would continue to provide Control Area services, using existing ISO facilities, systems, and personnel, consisting of:
  - Coordination with adjacent Control Areas for interchange scheduling and checkout;
  - Coordinating Inter-Control Area switching operations;

- Maintaining a back-up Control Center;
- Real-time balancing of load and resources;
- Compliance with all NERC policies and WECC Minimum Operating Reliability Criteria;
- Management of Unscheduled (Loop) Flow mitigation (particularly on WECC Paths 66 and 15), including controller adjustments with BPA, real time schedule curtailments with BPA, as well as coordinated and proprietary operation of phase shifters;
- Inter-Control Area Inadvertent Energy exchange reconciliation;
- AGC/Regulation for the Control Area;
- Bulk System Voltage Control;
- Outage Coordination and Management;
- Dispatch Services;
- Pre-Scheduling and real-time Scheduling Services (Day-Ahead, Hour-Ahead, and real time);
- NERC Tagging Coordination;
- Operations Planning and Engineering Studies;
- System Security Analysis;
- System Emergency Management; and
- Control Area to Control Area Mutual Emergency Support

To enter into such an arrangement with the ISO, Western and the ISO would negotiate and execute an MSS agreement. Neither a Participating Generator Agreement nor Utility Distribution Company Operating Agreement would be required.

B. Participating TO

The ISO's transmission Access Charge methodology allows Transmission Owners to turn over Operational Control of their transmission to the ISO by executing the Transmission Control Agreement. If Western were to turn over operational control of the its transmission to the ISO, then its Transmission Revenue Requirement would be integrated into the Northern TAC rate, and the ISO would pay Western its FERC-approved TRR. Any Scheduling Coordinator using the transmission would pay the same Northern TAC rate.

The corrected cost-benefit analysis shows that Western's option to join the ISO as a Participating Transmission Owner (particularly with MSS operations) would offer substantial cost savings relative to Western's Federal Control Area Options.

VIII. Conclusions

Western's cost-benefit analysis presented in the June 12, 2003 Navigant Report is based on erroneous and inappropriate assumptions that lead to a significant overstatement of net costs under the PTO and MSS operational alternatives as well as understated net costs of the Federal Control Area Options. A correction of these erroneous and inappropriate assumptions, even under very conservative scenarios, yields the result that, instead of the approximately $10 million annual cost advantage of FCA Options in Western's analysis, the formation of a ***Federal Control Area*** would actually result in ***direct annual costs that are $9-16 million higher than operating as an MSS, and between $15-31 million higher than joining the ISO as a Participating TO***. Operating an MSS as a PTO yields the highest costs savings relative to Western's FCA Options. However, these direct additional costs of forming a Federal Control Area do not capture the significant indirect costs that Western's formation of a new Control Area within the ISO's Northern California service area would impose in terms of system operations, inefficient seams and configuration issues, and the apparently-planned cross-subsidization of Western customers through inappropriate surcharges on Western's PACI transmission system.

A number of operational concerns have arisen in the analysis of the Western proposal that could have adverse implications for grid reliability and the west-wide interconnection. Increased Ancillary Service requirements alone due to the Western FCA result in additional capacity needs that would impact the water flows for USBR's generators. Seams issues among Control Areas would only be exacerbated with the addition of a new Control Area and result in increase complexity and workload for all parties. Issues on both internal California paths and on the California-Oregon Intertie would need to be mitigated if Western moved forward with its proposal. WECC standards must be adhered to, along with Good Utility Practice. Past operating practices by Western have led the ISO to believe that Western may find it difficult to meet these requirements.

Any decision on the Western 2005 Marketing Plan should be made on an informed basis with the best, most accurate information available. It is apparent that Western's Navigant Report presents an inaccurate analysis, primarily due to the inconsistent and inaccurate assumptions used as the basis for the analysis and the mischaracterization of certain ISO Tariff requirements, including the obligations associated with Ancillary Services and with Market settlements. Facts are still being gathered and a final decision should not be made until all parties have an opportunity to review a more accurate and balanced analysis.

If Western also were to become a Participating TO, rate-pancaking would be avoided, approved high-voltage transmission cost increases could be recovered from the entire ISO Control Area, and the combined MSS+PTO option would provide Western and its customers the largest cost savings relative to the Federal Control Area plan.

The ISO remains committed to working with Western, specifically on the terms of a Metered Subsystem agreement that would address the needs of Western, the United States Bureau of Reclamation, and their federal power customers. The ISO's MSS and PTO Options continue to be available as a lower cost, more reliable option for Western's customers.

ATTACHMENT A

Summary of 2005 Costs

Operational Alternative	2005 Net Costs	Savings vs. FCA Option
PTO+MSS	$22-29 million	$16-31 million
PTO	$28-31 million	$15-25 million
MSS	$37-37 million	$9-16 million
FCA (Group B customers)	$45-53 million	$0

Source: Attachment A, Table 1.

Summary of 2006-2019 Costs

(in 2005 dollars)

Operational Alternative	2005 Net Costs	Savings vs. FCA Option
PTO+MSS	$20-28 million	$16-31 million
PTO	$27-30 million	$14-24 million
MSS	$35-36 million	$8-15 million
FCA (Group B customers)	$44-51 million	$0

Source: Attachment A, Table 2 (2005 differs only due to start-up costs).

TABLE 1: COSTS AND BENEFITS OF WESTERN'S ISO AND CONTROL AREA OPTIONS
(Revised & Corrected "Table 1" of Navigant Study - Year 2005)

CATEGORY	ISO PARTICIPATION: PTO+MSS COMBINATION	ISO PARTICIPATION: PTO w/o MSS	METERED SUBSYSTEM (w/o PTO)	WESTERN CONTROL AREA: GROUP - A CUSTOMERS	WESTERN CONTROL AREA: GROUP - B CUSTOMERS	WESTERN CONTROL AREA: GROUP - C CUSTOMERS	WESTERN CONTROL AREA: GROUP - D CUSTOMERS
I. Cost Components							
A. GRID MANAGEMENT CHARGE	$4,412,220	$5,430,405	$3,656,890	$2,457,820	$2,065,164	$1,976,171	$1,976,171
B. TRANSMISSION SERVICE							
1. PTO pays TAC on MSS Gross Load	$21,068,202	$21,068,202	$16,631,445	$16,631,445	$16,631,445	$16,631,445	$16,631,445
2. PTO pays TAC on MSS Net Load	$16,631,445	$21,068,202	$16,631,445	$16,631,445	$16,631,445	$16,631,445	$16,631,445
C. ANCILLARY SERVICES	$0	$0	$0	$0	$0	$0	$0
D. TRANSMISSION CONGESTION CHARGE							
1. Only 80% hedged with FTRs/CRRs	$680,959	$680,959	$0	$0	$0	$0	$0
2. Fully hedged with FTRs/CRRs	$0	$0	$0	$0	$0	$0	$0
E. RELIABILITY SERVICES CHARGE	$3,645,585	$3,645,585	$7,291,171	$7,291,171	$7,291,171	$7,291,171	$3,645,585
F. DEVIATION CHARGES	$0	$0	$0	$0	$0	$0	$0
G. UNACCOUNTED FOR ENERGY CHARGE H. NEUTRALITY CHARGE I. GRID OPERATIONS CHARGE	$1,096,143	$1,804,977	$1,096,143	$832,801	$832,801	$832,801	$832,801
J. CAPITAL COSTS							
1. Western's PTO cost assumption	$4,126,000	$4,126,000	$4,126,000	$7,931,000	$7,931,000	$7,931,000	$7,931,000
2. Reduced Western's PTO cost assumption	$2,713,000	$2,713,000	$2,713,000	$7,931,000	$7,931,000	$7,931,000	$7,931,000
K. OPERATING EXPENSES							
1. Western's PTO cost assumption	$12,047,000	$12,047,000	$12,047,000	$19,000,000	$19,000,000	$19,000,000	$19,000,000
2. Reduced Western's PTO cost assumption	$11,122,500	$11,122,500	$11,122,500	$19,000,000	$19,000,000	$19,000,000	$19,000,000
L. TRANSMISSION REVENUE REQUIREMENT							
1. Navigant assumption	$9,565,880	$9,565,880	$9,565,880	$9,565,880	$9,565,880	$9,565,880	$9,565,880
2. WAPA data in TAC proceeding	$12,497,000	$12,497,000	$12,497,000	$12,497,000	$12,497,000	$12,497,000	$12,497,000
Total Costs -- Scenario 1	$56,641,990	$58,369,008	$54,414,529	$63,710,117	$63,317,461	$63,228,468	$59,582,883
Total Costs -- Scenario 2	$52,117,894	$58,281,669	$55,008,149	$66,641,237	$66,248,581	$66,159,588	$62,514,003
II. Benefit Components							
A. ANCILLARY SERVICES SALES							
1. FCA requirement = 5%	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378
2. FCA req. = single largest contingency	$17,848,378	$17,848,378	$17,848,378	$13,242,372	$13,242,372	$13,242,372	$13,242,372
B. TRANSMISSION ACCESS CHARGE PAYMENT							
1. Navigant assumption	$9,565,880	$9,565,880	$0	$0	$0	$0	$0
2. WAPA data in TAC proceeding	$12,497,000	$12,497,000	$0	$0	$0	$0	$0
Total Benefits -- Scenario 1	$27,414,258	$27,414,258	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378
Total Benefits -- Scenario 2	$30,345,378	$30,345,378	$17,848,378	$13,242,372	$13,242,372	$13,242,372	$13,242,372
NET COSTS (BENEFITS) -- Scenario 1	$29,227,732	$30,954,750	$36,566,151	$45,861,739	$45,469,083	$45,380,090	$41,734,505
NET COSTS (BENEFITS) -- Scenario 2	$21,772,516	$27,936,291	$37,159,771	$53,398,865	$53,006,210	$52,917,217	$49,271,631
SAVINGS vs. FCA OPTION B -- Scenario 1	$16,241,352	$14,514,333	$8,902,932	($392,656)	$0	$88,993	$3,734,579
SAVINGS vs. FCA OPTION B -- Scenario 2	$31,233,694	$25,069,919	$15,846,438	($392,656)	$0	$88,993	$3,734,579

Notes:
Scenario 1 represents a more favorable set of assumptions for the FCA options.
Scenario 2 represents a more favorable set of assumptions for the ISO options.

Sources:
I. A-I: Attachment A, Tables 3 & 4.
I. J-K: In Scenario 1, PTO+MSS and MSS capital and operating costs assumed to equal Western's assumed PTO capital costs;
In Scenario 2, capital and operating costs for all ISO Options equal to Western's PTO cost assumption less half of Western's assumed IT-related infrastructure costs.
These adjustments also reflect the fact that labor and capital costs for the MSS and PTO options (as well as the PTO+MSS option) should be the same.
In addition, annual operating expenses of the control area options were increased by $1.5 million to reflect the payments that Western would make to the ISO in its role as the COI Path operator and transmission coordinator.
I. L: Transmission Revenue Requirement in Scenario 2 calculated as HV TRR ($21.724 million filed in TAC proceeding) less Existing Contract Revenue ($9.227 million filed in TAC proceeding).
II. A: Attachment A, Tables 3 & 4.
II. B: Transmission access charge payment in each scenario is equal to the transmission revenue requirement.

TABLE 2: COSTS AND BENEFITS OF WESTERN'S ISO AND CONTROL AREA OPTIONS
(Revised & Corrected "Table 2" of Navigant Study - Years 2006-2019)

CATEGORY	ISO PARTICIPATION		METERED SUBSYSTEM (w/o PTO)	WESTERN CONTROL AREA			
	PTO+MSS COMBINATION	PTO w/o MSS		GROUP - A CUSTOMERS	GROUP - B CUSTOMERS	GROUP - C CUSTOMERS	GROUP - D CUSTOMERS
I. Cost Components							
A. GRID MANAGEMENT CHARGE	$4,412,220	$5,430,405	$3,656,890	$2,457,820	$2,065,164	$1,976,171	$1,976,171
B. TRANSMISSION SERVICE							
1. PTO pays TAC on MSS Gross Load	$21,068,202	$21,068,202	$16,631,445	$16,631,445	$16,631,445	$16,631,445	$16,631,445
2. PTO pays TAC on MSS Net Load	$16,631,445	$21,068,202	$16,631,445	$16,631,445	$16,631,445	$16,631,445	$16,631,445
C. ANCILLARY SERVICES	$0	$0	$0	$0	$0	$0	$0
D. TRANSMISSION CONGESTION CHARGE							
1. Only 80% hedged with FTRs/CRRs	$680,959	$680,959	$0	$0	$0	$0	$0
2. Fully hedged with FTRs/CRRs	$0	$0	$0	$0	$0	$0	$0
E. RELIABILITY SERVICES CHARGE	$3,645,585	$3,645,585	$7,291,171	$7,291,171	$7,291,171	$7,291,171	$3,645,585
F. DEVIATION CHARGES	$0	$0	$0	$0	$0	$0	$0
G. UNACCOUNTED FOR ENERGY CHARGE H. NEUTRALITY CHARGE I. GRID OPERATIONS CHARGE	$1,096,143	$1,804,977	$1,096,143	$832,801	$832,801	$832,801	$832,801
J. CAPITAL COSTS							
1. Western's PTO cost assumption	$2,826,000	$2,826,000	$2,826,000	$6,001,000	$6,001,000	$6,001,000	$6,001,000
2. Reduced Western's PTO cost assumption	$1,413,000	$1,413,000	$1,413,000	$6,001,000	$6,001,000	$6,001,000	$6,001,000
K. OPERATING EXPENSES							
1. Western's PTO cost assumption	$12,047,000	$12,047,000	$12,047,000	$19,000,000	$19,000,000	$19,000,000	$19,000,000
2. Reduced Western's PTO cost assumption	$11,122,500	$11,122,500	$11,122,500	$19,000,000	$19,000,000	$19,000,000	$19,000,000
L. TRANSMISSION REVENUE REQUIREMENT							
1. Navigant assumption	$9,565,880	$9,565,880	$9,565,880	$9,565,880	$9,565,880	$9,565,880	$9,565,880
2. WAPA data in TAC proceeding	$12,497,000	$12,497,000	$12,497,000	$12,497,000	$12,497,000	$12,497,000	$12,497,000
Total Costs -- Scenario 1	$55,341,990	$57,069,008	$53,114,529	$61,780,117	$61,387,461	$61,298,468	$57,652,883
Total Costs -- Scenario 2	$50,817,894	$56,981,669	$53,708,149	$64,711,237	$64,318,581	$64,229,588	$60,584,003
II. Benefit Components							
A. ANCILLARY SERVICES SALES							
1. FCA requirement = 5%	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378
2. FCA req. = single largest contingency	$17,848,378	$17,848,378	$17,848,378	$13,242,372	$13,242,372	$13,242,372	$13,242,372
B. TRANSMISSION ACCESS CHARGE PAYMENT							
1. Navigant assumption	$9,565,880	$9,565,880	$0	$0	$0	$0	$0
2. WAPA data in TAC proceeding	$12,497,000	$12,497,000	$0	$0	$0	$0	$0
Total Benefits -- Scenario 1	$27,414,258	$27,414,258	$17,848,378	$17,848,378	$17,848,378	$17,848,378	$17,848,378
Total Benefits -- Scenario 2	$30,345,378	$30,345,378	$17,848,378	$13,242,372	$13,242,372	$13,242,372	$13,242,372
NET COSTS (BENEFITS) -- Scenario 1	$27,927,732	$29,654,750	$35,266,151	$43,931,739	$43,539,083	$43,450,090	$39,804,505
NET COSTS (BENEFITS) -- Scenario 2	$20,472,516	$26,636,291	$35,859,771	$51,468,865	$51,076,210	$50,987,217	$47,341,631
SAVINGS vs. FCA OPTION B -- Scenario 1	**$15,611,352**	**$13,884,333**	**$8,272,932**	**($392,656)**	**$0**	**$88,993**	**$3,734,579**
SAVINGS vs. FCA OPTION B -- Scenario 2	**$30,603,694**	**$24,439,919**	**$15,216,438**	**($392,656)**	**$0**	**$88,993**	**$3,734,579**

Notes:
Scenario 1 represents a more favorable set of assumptions for the FCA options.
Scenario 2 represents a more favorable set of assumptions for the ISO options.

Sources:
I. A-I: Attachment A, Tables 3 & 4.
I. J-K: In Scenario 1, PTO+MSS and MSS capital and operating costs assumed to equal Western's assumed PTO capital costs;
In Scenario 2, capital and operating costs for all ISO Options equal to Western's PTO cost assumption less half of Western's assumed IT-related infrastructure costs.
These adjustments also reflect the fact that labor and capital costs for the MSS and PTO options (as well as the PTO+MSS option) should be the same.
In addition, annual operating expenses of the control area options were increased by $1.5 million to reflect the payments that Western would make to the ISO in its role as the COI Path operator and transmission coordinator.
I. L: Transmission Revenue Requirement in Scenario 2 calculated as HV TRR ($21.724 million filed in TAC proceeding) less Existing Contract Revenue ($9.227 million filed in TAC proceeding).
II. A: Attachment A. Tables 3 & 4.
II. B: Transmission access charge payment in each scenario is equal to the transmission revenue requirement.

TABLE 3: SUMMARY OF BILLING UNITS
FIGURES IN MEGAWATT-HOURS
(HIGHLIGHTED FIGURES REFLECT ADJUSTMENTS TO WESTERN'S ASSUMPTIONS)

CATEGORY	ISO PARTICIPATION			WESTERN CONTROL AREA			
COST COMPONENT	PTO+MSS COMBINATION	PTO w/o MSS	METERED SUBSYSTEM (w/o PTO)	GROUP - A CUSTOMERS	GROUP - B CUSTOMERS	GROUP - C CUSTOMERS	GROUP - D CUSTOMERS
A. GRID MANAGEMENT CHARGE							
- CONTROL AREA SERVICES	6,238,310	7,673,249	6,238,310	3,873,588	3,237,151	3,203,080	3,203,080
- INTER-ZONAL SCHEDULING	2,350,418	2,350,418	0	0	0	0	0
- ASREO	95,803	281,524	95,803	232,513	204,638	140,295	140,295
B. TRANSMISSION SERVICE							
1. PTO pays TAC on MSS Gross Load							
- LOCAL COMPONENT	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936
- REGIONAL COMPONENT	6,942,221	6,942,221	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936
2. PTO pays TAC on MSS Net Load							
- LOCAL COMPONENT	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936
- REGIONAL COMPONENT	4,215,936	6,942,221	4,215,936	4,215,936	4,215,936	4,215,936	4,215,936
C. ANCILLARY SERVICES							
- SPINNING RESERVE	0	0	0	0	0	0	0
- NON-SPINNING RESERVE	0	0	0	0	0	0	0
- REPLACEMENT RESERVE	0	0	0	0	0	0	0
- REGULATION	0	0	0	0	0	0	0
D. TRANSMISSION CONGESTION CHARGE							
1. Only 80% hedged with FTRs/CRRs	75,213	75,213	0	0	0	0	0
2. Fully hedged with FTRs/CRRs	0	0	0	0	0	0	0
E. RELIABILITY SERVICES CHARGE	1,601,540	1,601,540	3,203,080	3,203,080	3,203,080	3,203,080	1,601,540
F. DEVIATION CHARGES	0	0	0	0	0	0	0
G. UNACCOUNTED FOR ENERGY CHARGE H. NEUTRALITY CHARGE I. GRID OPERATIONS CHARGE	4,215,936	6,942,221	4,215,936	3,203,080	3,203,080	3,203,080	3,203,080
A. ANCILLARY SERVICES SALES							
1. FCA requirement = 5%							
- SPINNING RESERVE	1,742,833	1,742,833	1,742,833	1,742,833	1,742,833	1,742,833	1,742,833
- NON-SPINNING RESERVE	5,472,260	5,472,260	5,472,260	5,472,260	5,472,260	5,472,260	5,472,260
- REPLACEMENT RESERVE	0	0	0	0	0	0	0
- REGULATION	388,631	388,631	388,631	388,631	388,631	388,631	388,631
2. FCA req. = single largest contingency							
- SPINNING RESERVE	1,742,833	1,742,833	1,742,833	1,293,072	1,293,072	1,293,072	1,293,072
- NON-SPINNING RESERVE	5,472,260	5,472,260	5,472,260	4,060,072	4,060,072	4,060,072	4,060,072
- REPLACEMENT RESERVE	0	0	0	0	0	0	0
- REGULATION	388,631	388,631	388,631	288,339	288,339	288,339	288,339

TABLE 3: SUMMARY OF BILLING UNITS
FIGURES IN MEGAWATT-HOURS
(HIGHLIGHTED FIGURES REFLECT ADJUSTMENTS TO WESTERN'S ASSUMPTIONS)

Notes:

Western's study did not consider the PTO+MMS option.

COST COMPONENTS

A. Billing units for FCA-Group D are equal to the billing units for FCA-Group C. This adjustment is consistent with the fact that, even if dynamically scheduled, GMC would still be charged (on a net basis) to Western's load inside the ISO service area.

B. Under Scenario 1, in the PTO+MSS scenario, billing units are equal to Navigant's assumed billing units for a PTO.
Under Scenario 2, in the PTO+MSS option, Western is assumed to pay access charges on its net load, consistent with a recent FERC ruling.
The assumed billing units for the PTO+MSS option in this scenario are equal to Navigant's assumed billing units for the MSS option.

C. Replacement reserve purchases were eliminated, because Western self-supplies its energy and ancillary services; moreover, the ISO no longer buys replacement reserves and does not plan to do so in the futu

D. Scenario 1 assumes that Western would receive financial transmission rights (or congestion revenue rights) that would provide a very significant but not full financial hedge against congestion costs under th
In this case, unhedged congestion is assumed to be 20% of Navigant's assumed congestion billing units in the PTO scenarios (i.e., Western is hedged against 80% of congestion costs).
Scenario 2 assumes that Western would be fully hedged through FTRs/CRRs and thus incurs no congestion costs under the PTO options.
In addition, in both scenarios the incidence of transmission congestion on COI (in the import direction) is assumed to be 16% (rather than Western's 26%) based on actual congestion experienced on COI in 2

E. Billing units for the PTO+MMS, PTO and FCA Group D options are assumed to be 50% of those of FCA Groups A-C options, since PG&E R/S charges would not apply to PTO service area or load entirely i
note, however, that PG&E R/S charges likely would apply to partially-supplied load points under both PTO and FCA-D options. MSS billing units assumed equal to FCA Groups A-C billing units.

F. Deviation costs are assumed to be zero since Western will at times be "long" and at other times "short" and this will average out over time.
This is consistent with Western's assumption that it will fully supply its own loads.

G-I. Billing units for the PTO+MSS option are equal to Western's assumption for the MSS option.
Billing units for FCA-Group D set to equal the billing units for FCA-Group C. This adjustment is consistent with the fact that, even if dynamically scheduled, these items would still be charged (on a net basis) to Western's load inside the ISO service area.

BENEFIT COMPONENTS

A. Under Scenario 1, ancillary service (AS) requirements are assumed to be 5% regardless of whether Western joins the ISO (as a PTO or MSS) or forms its own control area.
Under Scenario 2, ancillary service sales under FCA options assume that the single largest contingency requirement reduces generating capacity available for AS sales by an average of 280MW during 80% o

TABLE 4: SUMMARY OF RATE INPUTS
FIGURES IN $ / MWH
(HIGHLIGHTED FIGURES REFLECT ADJUSTMENTS TO WESTERN'S ASSUMPTIONS)

COST CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019
A. GRID MANAGEMENT CHARGE															
- CONTROL AREA SERVICES	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570	$0.570
- INTER-ZONAL SCHEDULING	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321	$0.321
- ASREO	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082	$1.082
B. TRANSMISSION SERVICE															
- LOCAL COMPONENT	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318	$2.318
- REGIONAL COMPONENT	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627	$1.627
C. ANCILLARY SERVICES															
- SPINNING RESERVE	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749	$2.749
- NON-SPINNING RESERVE	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551	$1.551
- REPLACEMENT RESERVE	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717	$1.717
- REGULATION	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761	$11.761
D. TRANSMISSION CONGESTION CHARGE	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054	$9.054
E. RELIABILITY SERVICES CHARGE	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276	$2.276
F. DEVIATION CHARGES	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687	$5.687
G. UNACCOUNTED FOR ENERGY CHARGE															
H. NEUTRALITY CHARGE	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260	$0.260
I. GRID OPERATIONS CHARGE															

Notes:

A. GMC charges assumed to remain constant in real dollars over the study period, consistent with Western's assumption that its operating costs remain constant in real terms.
B. Transmission service rates assumed to remain constant in real dollars over the study period, consistent with Western's assumption that its transmission revenue requirement remains constant in real terms.
C. AS prices calculated over the period October 2001 through April 2003, which yields an estimate of average AS prices under reasonably normal market conditions, and held constant in real terms.
D. Transmission congestion charge is the rate assumed by Western for 2005, held constant in real terms.
E. Reliability service charge is the rate assumed by Western for 2005, held constant in real terms.
F. Deviation charge is the rate assumed by Western for 2005, held constant in real terms.
G-I. The combined cost of UFE, neutrality, and the grid operations charges is assumed to be $0.26/MWh, consistent with actual 2002 operational experience, and assumed to remain constant in real terms, consistent with Western's assumption that its operating costs remain constant in real terms.